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DUKE ENERGY CAROLINAS

TABLE 1-A
SC SUPPLEMENTAL PORTFOLIOS KEY INPUT AND ASSUMPTIONS

PORTFOLIO OUTCOME	IRP FILING	IRP PATHWAY	CARBON POLICY	FEDERAL SOLAR INVESTMENT TAX CREDIT EXTENSION	ANNUAL SOLAR INTERCONNECTION LIMITS [MW]	PERCENT OF FUTURE SOLAR AS SINGLE AXIS TRACKING	$38/MWH SOLAR PPA AS SELECTABLE RESOURCE	NATURAL GAS PRICE FORECAST	BATTERY COST FORECAST
Base Case without Carbon Policy	Original	A	No Carbon Policy	No Extension	500	60%	Extended	10 Years Market + Fundamental Forecast	Carolinas Specific Forecast
	Modified	A1	No Carbon Policy	Extension	750	100%	Included	10 Years Market + Fundamental Forecast	Carolinas Specific Forecast
	Modified	A2	No Carbon Policy	Extension	750	100%	Included	18 Months Market + Fundamental Forecast	2020 NREL ATB Low Forecast
Base Case with Carbon Policy	Original	B	With Carbon Policy	No Extension	500	60%	Extended	10 Years Market + Fundamental Forecast	Carolinas Specific Forecast
	Modified	B1	With Carbon Policy	Extension	750	100%	Included	10 Years Market + Fundamental Forecast	Carolinas Specific Forecast
	Modified	B2	With Carbon Policy	Extension	750	100%	Included	18 Months Market + Fundamental Forecast	2020 NREL ATB Low Forecast
Earliest Practicable Coal Retirements	Original	C	With Carbon Policy	No Extension	500	60%	Extended	10 Years Market + Fundamental Forecast	Carolinas Specific Forecast
	Modified	C1	With Carbon Policy	Extension	750	100%	Included	10 Years Market + Fundamental Forecast	Carolinas Specific Forecast
	Modified	C2	With Carbon Policy	Extension	750	100%	Included	18 Months Market + Fundamental Forecast	2020 NREL ATB Low Forecast
70% CO_2 Reduction: Offshore Wind	Original	D	With Carbon Policy	No Extension	900	60%	Extended	10 Years Market + Fundamental Forecast	Carolinas Specific Forecast
	Modified	D1	With Carbon Policy	Extension	900	100%	Included	10 Years Market + Fundamental Forecast	Carolinas Specific Forecast
70% CO_2 Reduction: Nuclear SMR	Original	E	With Carbon Policy	No Extension	900	60%	Extended	10 Years Market + Fundamental Forecast	Carolinas Specific Forecast
	Modified	E1	With Carbon Policy	Extension	900	100%	Included	10 Years Market + Fundamental Forecast	Carolinas Specific Forecast
No New Gas Generation	Original	F	With Carbon Policy	No Extension	900	60%	Extended	10 Years Market + Fundamental Forecast	Carolinas Specific Forecast
	Modified	F1	With Carbon Policy	Extension	900	100%	Included	10 Years Market + Fundamental Forecast	Carolinas Specific Forecast

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TABLE 1-B
DEC SC SUPPLEMENTAL PORTFOLIOS MODELING RESULTS

	Duke Energy Carolinas																	
Pathway	**A1**		**A2**		**B1**		**B2**		**C1**		**C2**		**D1**		**E1**		**F1**	
System CO_2 Reduction (2030 | 2035)[1]	56%	53%	57%	54%	59%	64%	61%	65%	66%	66%	66%	67%	73%	75%	73%	75%	67%	75%
Present Value Revenue Requirement (PVRR) [$B][2]	$43.6		$43.5		$46.5		$47.0		$46.9		$47.5		$54.8		$52.4		$54.6	
Average Monthly Residential Bill Impact for a Household Using 1000kWh (by 2030 | by 2035)[3]	$7	$22	$7	$22	$11	$27	$11	$28	$15	$27	$17	$28	$25	$45	$23	$44	$10	$42
Average Annual Percentage Change in Residential Bills (through 2030 | through 2035)[3]	0.7%	1.3%	0.7%	1.3%	1.0%	1.6%	1.1%	1.6%	1.4%	1.6%	1.6%	1.6%	2.2%	2.5%	2.1%	2.4%	1.0%	2.3%
Total System Solar [MW][4, 5] by 2035	5,300		5,450		7,850		8,300		8,200		8,300		8,750		8,750		8,750	
Incremental Onshore Wind [MW][4] by 2035	0		0		600		600		600		750		1,250		1,250		1,250	
Incremental Offshore Wind [MW][4] by 2035	0		0		0		0		0		0		1,350		150		150	
Incremental SMR Capacity [MW][4] by 2035	0		0		0		0		0		0		0		700		700	
Incremental Storage [MW][4, 6] by 2035	350		350		550		1,500		600		1,550		2,400		2,400		2,400	
Incremental Gas [MW][4] by 2035	3,500		3,500		3,050		2,150		5,200		4,300		4,300		3,950		0	
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW][7] by 2035	1,225		1,225		1,225		1,225		1,225		1,225		1,850		1,850		1,850	
Remaining Dual Fuel Coal Capacity [MW][4, 8] by 2035	3,050		3,050		3,050		3,050		0		0		0		0		2,200	
Coal Retirements	Most Economic		Most Economic		Most Economic		Most Economic		Earliest Practicable		Earliest Practicable		Earliest Practicable[9]		Earliest Practicable[9]		Most Economic	
Dependency on Technology & Policy Advancement	◔		◑		◔		◑		◑		◕		◕		●		●	

[1]Combined DEC/DEP System CO_2 Reductions from 2005 baseline in Duke's Base Gas Assumption

[2]PVRRs exclude the cost of CO_2 as tax. PVRR results reflect Duke's Base Gas and Battery Cost Assumptions

[3]Represents specific IRP portfolio's incremental costs included in IRP analysis; does not include complete costs for other initiatives that are constant throughout the IRP or that may be pending before state commissions

[4]All capacities are Total/Incremental nameplate capacity within the IRP planning horizon

[5]Total solar nameplate capacity includes 975 MW connected in DEC as of year-end 2020 (projected)

[6]Includes 4-hr and 6-hr grid-tied storage, storage at solar plus storage sites, and pumped storage hydro

[7]Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour

[8]Remaining coal units are capable of co-firing on natural gas

[9]Earliest Practicable retirement dates with delaying one (1) Belews Creek unit to EOY 2029 for integration of offshore wind/SMR by 2030

Legend:
- ○ Not Dependent
- ◔ Slightly Dependent
- ◑ Moderately Dependent
- ◕ Mostly Dependent
- ● Completely Dependent

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DUKE ENERGY® CAROLINAS

TABLE 1-C
DEC/DEP COMBINED SUPPLEMENTAL PORTFOLIOS MODELING RESULTS

	DEP/DEC Combined System								
Pathway	**A1**	**A2**	**B1**	**B2**	**C1**	**C2**	**D1**	**E1**	**F1**
System CO_2 Reduction (2030 | 2035)[1]	56% 53%	57% 54%	59% 64%	61% 65%	66% 66%	66% 67%	73% 75%	73% 75%	67% 75%
Present Value Revenue Requirement (PVRR) [$B][2]	$78.6	$78.8	$81.6	$82.4	$83.2	$83.8	$100.2	$95.2	$107.2
Total System Solar [MW][3,4] by 2035	10,500	10,350	15,100	15,600	15,550	15,600	18,350	18,350	18,350
Incremental Onshore Wind [MW][3] by 2035	0	0	1,500	1,500	1,350	1,500	2,850	2,850	2,850
Incremental Offshore Wind [MW][3] by 2035	0	0	0	0	0	0	2,650	250	2,650
Incremental SMR Capacity [MW][3] by 2035	0	0	0	0	0	0	0	1,350	700
Incremental Storage [MW][3,5] by 2035	600	1,600	1,900	3,400	2,000	3,400	4,350	4,350	7,350
Incremental Gas [MW][3] by 2035	8,850	7,950	7,500	6,100	9,600	8,250	6,400	6,100	0
Total Contribution from Energy Efficiency and Demand Response Initiatives [MW][6] by 2035	2,050	2,050	2,050	2,050	2,050	2,050	3,350	3,350	3,350
Remaining Dual Fuel Coal Capacity [MW][3,7] by 2035	3,050	3,050	3,050	3,050	0	0	0	0	2,200
Coal Retirements	Most Economic	Most Economic	Most Economic	Most Economic	Earliest Practicable	Earliest Practicable	Earliest Practicable[8]	Earliest Practicable[8]	Most Economic[9]
Dependency on Technology & Policy Advancement	◔	◑	◔	◑	◑	◕	◕	●	●

[1]Combined DEC/DEP System CO_2 Reductions from 2005 baseline in Duke's Base Gas Assumption

[2]PVRRs exclude the cost of CO_2 as tax. PVRR results reflect Duke's Base Gas and Battery Cost Assumptions

[3]All capacities are Total/Incremental nameplate capacity within the IRP planning horizon

[4]Total solar nameplate capacity includes 3,925 MW connected in DEC and DEP combined as of year-end 2020 (projected)

[5]Includes 4-hr and 6-hr grid-tied storage, storage at solar plus storage sites, and pumped storage hydro

[6]Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour

[7]Remaining coal units are capable of co-firing on natural gas

[8]Earliest Practicable retirement dates with delaying one (1) Belews Creek unit and Roxboro 1&2 to EOY 2029 for integration of offshore wind/SMR by 2030

[9]Most Economic retirement dates with delaying Roxboro 1&2 to EOY 2029 for integration of offshore wind by 2030

Legend:
- ○ Not Dependent
- ◔ Slightly Dependent
- ◑ Moderately Dependent
- ◕ Mostly Dependent
- ● Completely Dependent

expected to serve a critical role, enabling economic coal retirements while maintaining system reliability, with a gradual shift in mission over the long term, towards ultimately backstanding renewables and storage.

Figures 1-B and 1-C below show the transition from the 2021 generation resource mix to the 2035 resource mix under Portfolio C1 for DEC and the DEC/DEP Combined System.

FIGURE 1-B
DEC 2021 – 2035 CAPACITY UNDER PORTFOLIO C1

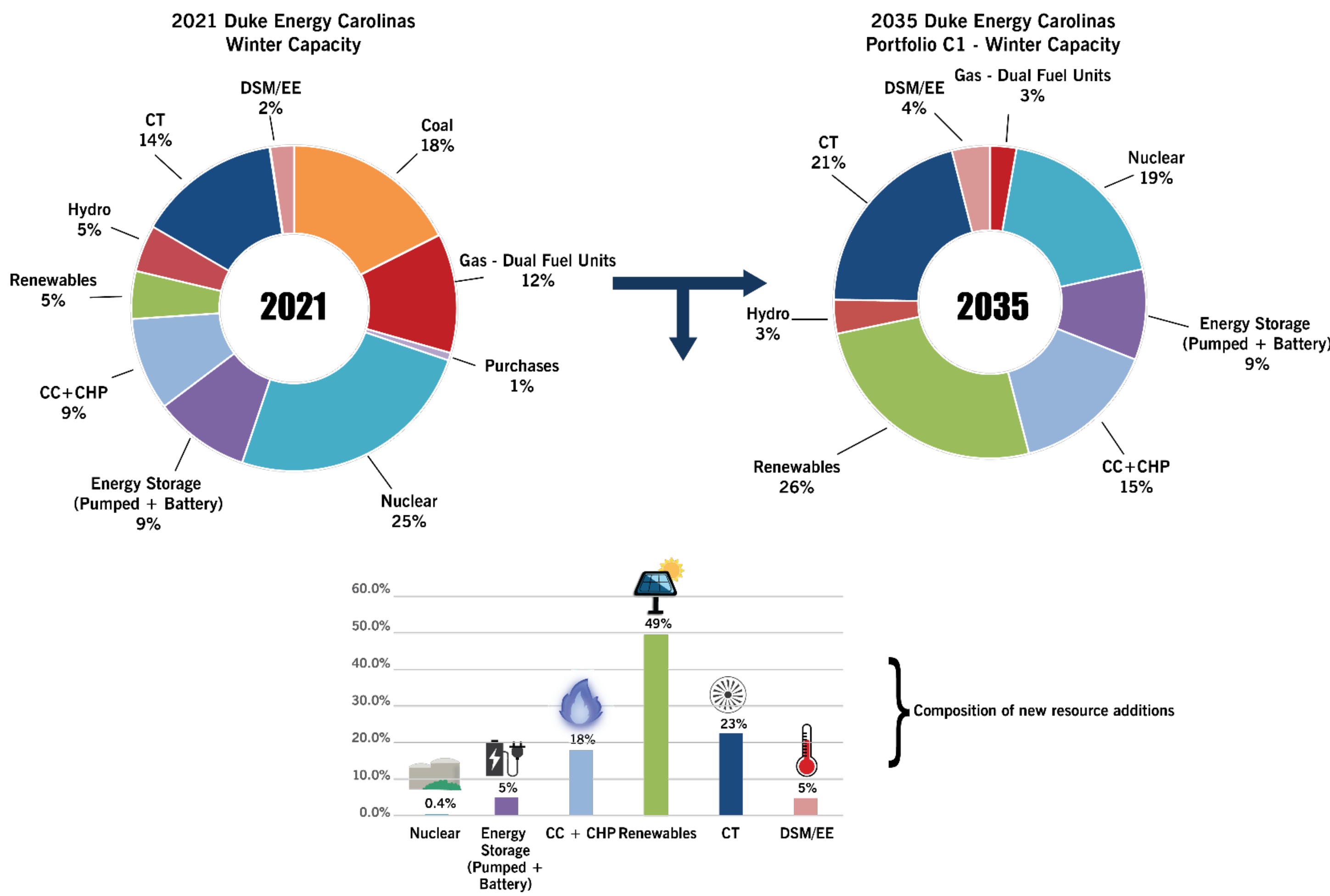

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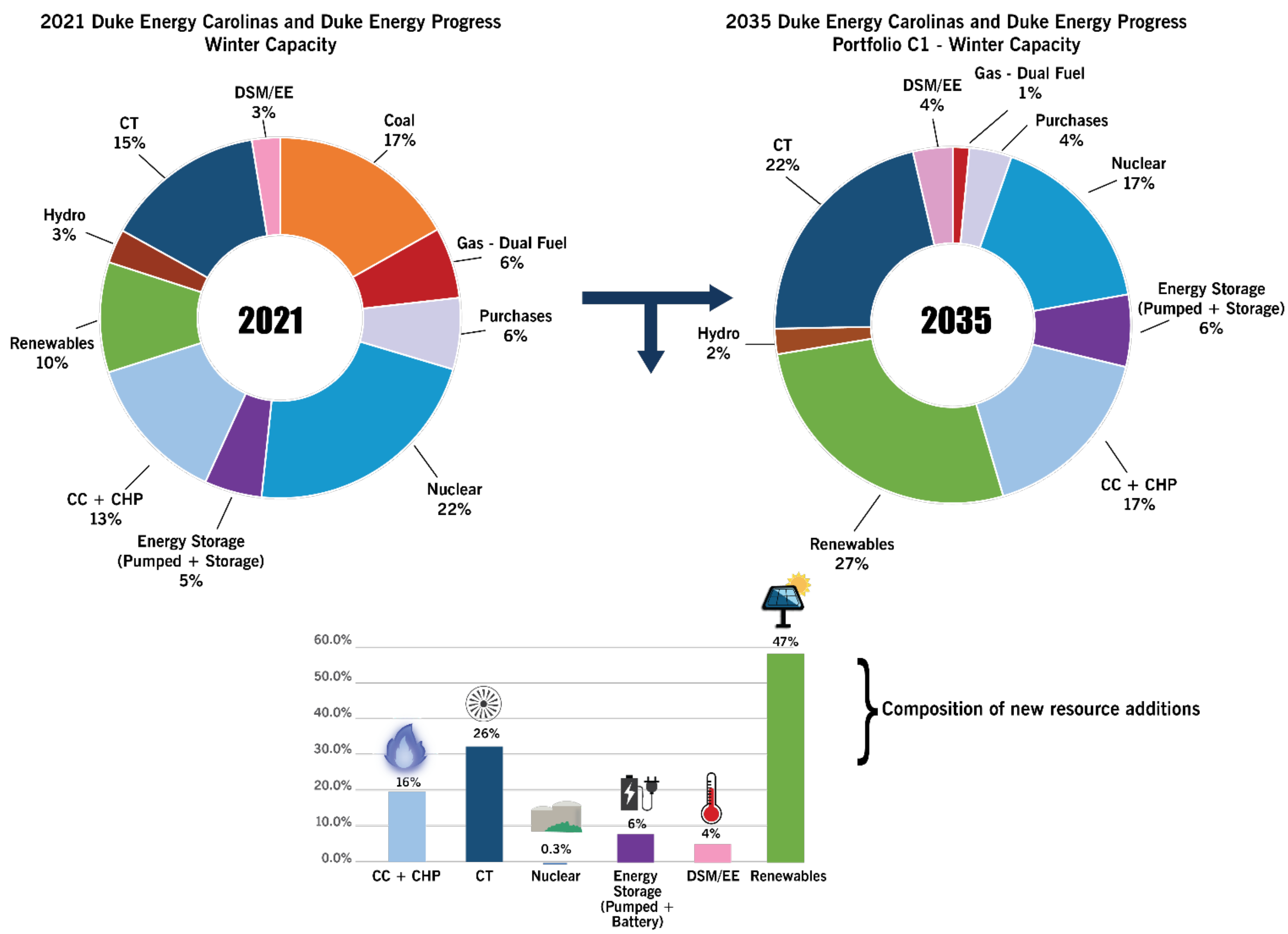
FIGURE 1-C
DEC/DEP COMBINED SYSTEM 2021 CAPACITY TO 2035 CAPACITY UNDER PORTFOLIO C1



of new solar resources that could be added in each year. In Order No. 2021-447, the Commission required DEC and DEP to modify these modeling assumptions to include an annual interconnection limitation of 750 MW. Accordingly, in Portfolios A1, A2, B1, B2, C1, and C2, DEC and DEP have expanded the annual interconnection limit to 750 MW, which includes 450 MW for DEC and 300 MW for DEP. The volumetric division between DEC and DEP is appropriate based on the saturation of solar in the DEP territory and the future solar development that is expected in both utilities. This is also equivalent to the proportional split between DEC and DEP in the September 2020 IRP. The annual interconnection limit in Portfolios D1, E1, and F1 remains 900 MW.

The 500 MW interconnection limitation in the September 2020 IRP was based on the actual average volume of solar the Companies have interconnected since 2014. The Companies have not achieved 750 MW of solar interconnections in a year previously and most recently achieved 320 MW of new solar interconnections in 2020. Accordingly, it is uncertain whether this amount of solar can be interconnected on an annual basis. The Companies will continue to monitor the pace and volume of new solar interconnections and adjust this modeling assumption in future IRPs.

$38/MWH SOLAR PPA OPTION

Order No. 2021-447 requires the Companies to include a solar PPA option as a selectable resource in the IRP. All of the SC Supplemental Portfolios include a solar PPA option priced at $38/MWh for a 20-year contract term. The Commission has required modeling at this price point based on the average price of successful bids in Tranche 1 of the CPRE program created pursuant to North Carolina law; however DEC's and DEP's ability to actually procure solar in the future at this price point is uncertain and will depend on future statutory and regulatory action.

In addition to the necessary future policy changes to facilitate any future solar procurement, several factors call into question the likelihood of actually acquiring the volumes of $38/MWh third-party solar shown in the SC Supplemental Portfolios. First, the volume of solar that could be procured at $38/MWh in the DEC/DEP service areas is uncertain. Notably, of the approximately 1,200 MW of solar resources procured over the first two tranches of the NC CPRE Program, only about half have been contracted at, or below, $38/MWh. Numerous factors, such as the competitive procurement structure and locational-specific costs (land availability/property taxes), can impact the cost-effectiveness and depth of market for new solar procurement. For example, existing laws governing renewable energy procurements conducted in the Companies' service area limit projects to Qualifying

Facilities (80 MW and under) under PURPA, while such limitations may not exist in other jurisdictions. Additionally, while the Company projects declining solar technology costs into the future, DEC and DEP also expect upward pressure on procurement bid prices as the solar ITC steps down and as it becomes more difficult to find solar facility sites that can cost-effectively accommodate larger project sizes and provide minimal interconnection costs. Said simply, the greater the solar saturation on the DEC and DEP systems, the harder it is to find inexpensive land with low interconnection costs.

In order to provide a balanced portfolio of solar generation across the planning horizon and in recognition of the uncertainty of the volume of solar PPAs that would be available on an annual basis under the prescribed parameters, the Companies divided the annual amount of utility cost-of-service (COS) solar and $38/MWh third-party PPA solar that can be connected to 375 MW each (50 percent of the 750 MW solar interconnection limit). The Companies believe this balance between third-party solar and utility COS-solar is appropriate to ensure a diverse mix of renewable resource types available to customers. It would be imprudent to rely entirely on purchased power for any one resource type, including solar. Finally, the total volume of new third-party solar selected over the 15-year planning horizon is over 3,400 MW, which is significant. For comparison, this is far in excess of the 400 MW (total, not annual) of third-party solar allowed to be selected in the applicable DESC resource plans included in DESC's most recent Modified IRP.

FIXED TILT VS SINGLE AXIS TRACKING SOLAR CONFIGURATIONS

In the September 2020 IRP, DEC and DEP assumed that 60% of new solar additions would be single-axis tracking and 40% would be fixed tilt. Since the time that those modeling assumptions were developed, updated results of CPRE Tranche 2 are available, which strongly indicate that new solar resources are most likely to be developed as single-axis tracking. In Order No. 2021-447, the Commission required DEC and DEP to modify these modeling assumptions to assume all future solar would be single-axis tracking. Accordingly, all of the SC Supplemental Portfolios reflect this change. The Companies will continue to monitor trends in the solar industry and make adjustments to solar technology assumptions as conditions warrant.

NREL ANNUAL TECHNOLOGY BASELINE (ATB) ADVANCED BATTERY COSTS

Order No. 2021-447 requires the Companies to conduct analysis using the NREL Annual Technology

Baseline (ATB) Low, or Advanced[1], case for battery storage in the IRP. SC Supplemental Portfolios A2, B2, and C2 utilize the 2020 NREL ATB Advanced price forecast for battery storage. The remaining SC Supplemental Portfolios rely on the Companies' internally generated battery storage cost forecasts from the September 2020 IRP that are representative of the costs to build and operate battery storage on the DEC system. Given the rapidly evolving nature of battery technologies, and to promote transparency of costs used in modeling battery storage, the Company is evaluating using published resources, such as the NREL ATB Moderate price forecast, as a starting point for battery storage costs in future IRPs.

The NREL ATB Advanced cost assumption was not used in all portfolios because there are substantial reasons to question its validity for use as a base planning assumption. The assumed cost declines of the "Advanced" case are exceedingly aggressive and are neither reasonable nor prudent for use as a base assumption for long-term planning.

As shown in Figure 2-A below, NREL's low cost projection aligns with the most aggressive cost decline projection from 19 published sources that were evaluated in NREL's "Cost Projections for Utility-Scale Battery Storage: 2020 Update" which was the basis of the 2020 NREL ATB[2].

[1] In the 2020 NREL ATB, the Low, Mid, and High naming convention for the technology costs was changed to Advanced, Moderate, and Conservative, respectively.

[2] Cole, Wesley, and A. Will Frazier. 2020. Cost Projections for Utility-Scale Battery Storage: 2020 Update. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-75385. https://www.nrel.gov/docs/fy20osti/75385.pdf

As shown above, by the end of the planning horizon, DEC is projecting approximately 7,900 MW of solar and wind resources on its system. The contribution of these resources towards meeting DEC's winter peak demand is approximately 580 MW by 2035.

Similar to the September 2020 IRP, solar that is forced into each portfolio is represented as either designated, mandated, or undesignated based on the definitions below:

- **Designated:** Facilities with executed contracts (included as "Designated" for the duration of the purchase power contract).

- **Mandated:** Capacity that is not yet under contract but is required through renewable energy programs driven by existing law (examples include future tranches of CPRE, the renewable energy procurement program for large customers, and community solar under NC HB 589 as well as SC Act 236).

- **Undesignated:** Additional capacity projected beyond what is already designated or mandated. Expiring solar contracts are assumed to be replaced in kind with undesignated solar additions. Such additions may include existing facilities or new facilities that enter into contracts that have not yet been executed. As described in the September 2020 IRP, the Companies assumed that there would be some materialization of solar from the interconnection queues above and beyond the capacity classified as "Mandated."

The volume of solar included as Designated, Mandated, and Undesignated in the SC Supplemental Portfolios is the same as that which was included for the September 2020 IRP.

Figure 2-B summarizes the incremental annual additions of solar in Portfolio C1. It is anticipated that a portion of the solar additions classified as Undesignated Solar will be third-party PPA solar materializing from the interconnection queue, as shown in Table Y-2. In years where Designated, Mandated, and Undesignated solar are included, the availability of model-selected solar (both $38/MWh PPA and utility COS) decreases, in order to maintain the 750 MW interconnection limitation. For example, in 2023, the Companies have forecasted approximately 675 MW of Designated/Mandated solar, which leaves 75 MW to be selected by the model. As seen below, the model selects the $38/MWh third party solar resource option for 75 MW to reach the 750 MW interconnection limit.[4]

[4] In some years the total nameplate capacity of solar exceeds 750 MW. This occurs because the model selects solar in 75 MW increments, and if, at any point, the amount of solar is less than the 450 MW limit in DEC and/or the 300 MW limit

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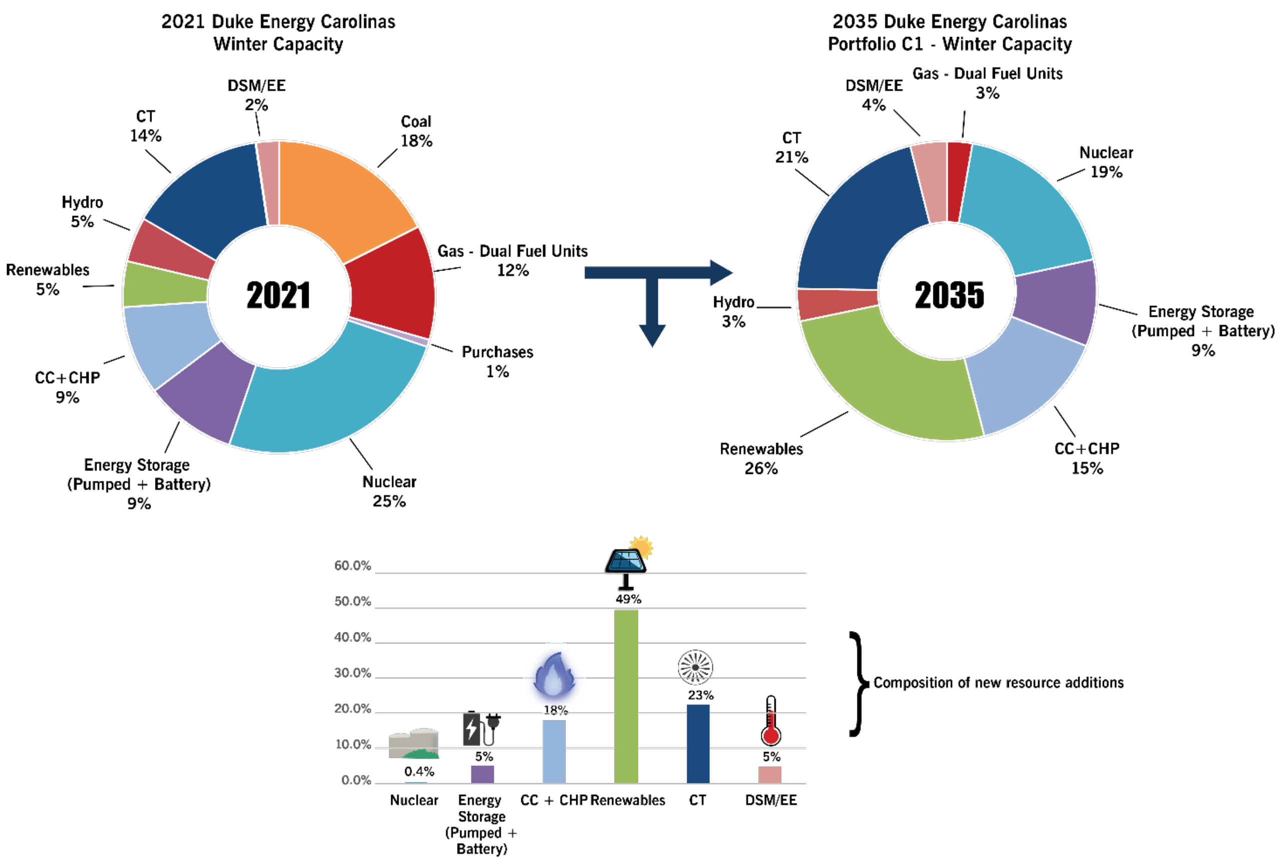
The following figures illustrate both the current and forecasted capacity for the DEC system, as projected by Portfolio C1. Figure 3-R depicts how the capacity mix for the DEC system changes with the passage of time. In 2035, Portfolio C1 projects that DEC will have a substantial reduction in its reliance on coal units and a significantly higher reliance on renewable resources as compared to the current state. It is of particular note that over 50% of the new resources added over the study period are solar, wind and storage resources.

As mentioned above, resources in Portfolio C1 are depicted in Figure 3-R below reflects a significant amount of growth in solar capacity with nameplate solar growing from 966 MW in 2021 to 7,449 MW by 2035.

FIGURE 3-R
PORTFOLIO C1 – DEC CAPACITY CHANGES OVER 15 YEAR PLANNING HORIZON[4]



[4] All capacity based on winter ratings except Renewables and Energy Storage which are based on nameplate.